ATTACHMENT 2

APPENDIX 1

EXCERPT FROM D.94-10-059 ON DIMENSIONS OF RELATIVE RISK BETWEEN SUPPLY AND DSM RESOURCES[1]

"Under traditional cost of service ratemaking, shareholders put up the initial capital for generation, transmission, distribution and storage facilities, and are therefore exposed to potential investment losses if the project does not operate at all, or it is removed from rate base because it goes out of service prematurely. However, as PG&E and SoCal explain in Exh. 337, under applicable PU Code sections, the Commission has the authority to allow utilities to recover close to the full investment costs of abandoned and out-of-service projects. For PG&E, there have been two proceedings relating to prematurely retired plant: Geysers Unit 15 and the Humboldt Bay Nuclear Power Plant. In each case, the Commission allowed PG&E to recover the undepreciated investments over five years with no return. Similarly, the Commission has also allowed SoCal to recover costs for gas transmission, distribution and storage projects that have never become used and useful, but not earn a return on those investments. (Exh. 337, pp. C-2 to C-4, D-1 to D-17.)

"Once a generation, transmission, distribution or storage facility is approved and placed in rate base, shareholder earnings are generally unaffected by changes in resource benefits, fuel prices or administrative costs over a wide range of performances. (Exh. 360, pp. 40-44; Exh. 337, pp. C-1 to C-5.) [footnote omitted] Although these changes may result in different benefits than forecast, traditional regulatory approaches do not look back and ascertain if the plant is "hitting target" as is done for DSM. (Exh. 354, p. 6.) Variations between forecasted and actual sales (throughput) also do not affect earnings on electric or core gas facilities, since these sales are currently given full balancing account treatment. The primary performance risk to shareholders relates to factors directly under the utility's influence, i.e., management of system operations and fuel or

[1] 57 CPUC 2d 1, at 54-58.

gas procurement contracts. These issues are reviewed in after-the-fact Commission reasonableness reviews. Over the past 10 years, PG&E has been disallowed less than 1% of electric operating expenses due to these performance factors. (Exh. 337, p. C-4.)

"As SoCal points out, the risk and reward relationship for noncore gas sales is quite different. (Exh. 337, pp. D-1-1 to D-1-16.) For this class of customers, utility earnings are affected by variations between estimated and actual throughput fluctuations. Under the recently adopted global settlement, SoCal is at 100% risk for any underrecovery of the noncore revenue requirement over the next five years. However, SoCal would also be able to increase earnings substantially from increased noncore demand. (See D.94-04-088, mimeo. p. 31.) Since the majority of utility DSM efforts address core gas and electric resource requirements, our consideration of relative risks and rewards focuses on these sectors.

"As an alternative to building its own generation facilities, an electric utility can purchase power from independent power producers or other utilities. [footnote omitted] Under traditional ratemaking treatment, these purchases represent a risk/reward profile similar to core gas procurement contracts. Shareholders do not earn any return on power purchase agreements with independent power producers or other utilities, but neither do they make any initial capital investment or assume a significant degree of forecasting risk. Under current ratemaking treatment, these purchase agreements are subject to balancing account treatment. Therefore, unless the electric utility is found to be imprudent in managing the contract, any differences between actual and forecasted fuel prices or resource benefits that are not assumed by the independent power producer are passed on to ratepayers. Figures 1 and 2 in Attachment 2 illustrate the relationship between earnings and performance for core gas operations, under traditional cost-of-service regulation. These relationships are equally illustrative of traditional ratemaking treatment for electric utility investments and power purchase agreements.

"As SoCal explains, ratemaking treatment for core gas procurement is rapidly changing, and with it the risk/reward profile of such resources. While PG&E's core gas purchases continue to receive full balancing account treatment subject to reasonableness reviews, SDG&E's and SoCal's core gas purchases now fall under new, performance-based gas procurement framework. As shown in Figure 3 of Attachment 2, shareholder earnings and penalties associated with gas purchases for SoCal and SDG&E are now linked to performance. Performance is defined as the extent to which actual gas purchase prices differ from a market-based benchmark price, rather than a comparison between actual and forecast gas prices.

"For the SoCal performance mechanism, there is a deadband between 100% and 104.5% of the benchmark price, wherein shareholders incur neither penalties or earnings, and ratepayers absorb the differences in gas costs. Beyond the deadband, the difference in costs is shared equally by ratepayers and shareholders. Extreme performance at either end of the performance curve could trigger regulatory review. SDG&E's performance mechanisms are being tested on an experimental basis.

"Similarly, traditional cost-of-service ratemaking for electric utility operations has given way to experiments in performance based ratemaking. Over the years, the Commission has selectively introduced more linkages between utility earnings and nuclear and coal plant performance. For example, for Mohave Coal Plant Units 1 and 2, shareholder earnings are linked to actual unit heat rates or plant capacity factors, relative to forecast. Earnings from the San Onofre and Palo Verde Nuclear Generating Stations depend on the difference in the cost of energy produced from that plant and the energy obtained form replacement energy sources. (Exh. 337, pp. H-3 to H-4. For the Diablo Canyon nuclear plant, the utility is paid based on actual plant output. It is estimated that PG&E will recover the full cost of the plant, plus earnings on the cost, plus an additional 173 million if PG&E continues to operate the plant over its 30-year life at the same overall 79% operating capacity factor achieved through December 31, 1993. (Exh. 337, p. C-5; Exh. 360, p. 47; D.88-12-083; CPUC 2d 189, at 242-244.)

"More recently, the Commission authorized a generation and dispatch shared-savings mechanism for SDG&E, which applies to the costs subject to Energy Cost Adjustment Clause (ECAC) balancing account treatment. Under this mechanism, SDG&E's shareholders and ratepayers share equally if actual energy costs fall (or increase) within one to six percent of a performance benchmark during the twelve months covered by the ECAC forecast. Below a one percent change, the additional costs or savings over the performance benchmark would be shared by ratepayers seventy percent and shareholders thirty percent. If SDG&E's costs exceed the benchmark by more than six percent, then ratepayers will pay the amount of these costs in excess of six percent subject to an ECAC reasonableness review. If SDG&E's cost falls below the benchmark by more than six percent, resulting in additional savings, ratepayers will automatically receive all of the benefits of the cost reductions beyond the six percent. (See D.93-06-092.)

"As described in previous sections, the next generation of DSM incentive mechanisms will have a risk/reward profile different from any of the individual supply-side options discussed above, as well as from the DSM incentive mechanisms we have authorized in the past. Although ratepayers continue to put up the investment capital for DSM programs, shareholders will now be at risk for 100% of any loses to that capital. Unlike a rate-based plant, shareholder earnings will vary in direct proportion to performance, i.e., realized net benefits, even when factors entirely beyond the utility's management control affect that performance. And unlike any of the DSM shared-savings incentives in the past, DSM performance will be measured over a 7 to 10-year period for the purpose of calculating both earnings and penalties, and earnings for each program year will be distributed to four equal installments over that timeframe.

"Given the differences in the risk/reward profiles of utility resource choices, what level of earnings is appropriate for the DSM incentive mechanisms adopted in today's decision? TURN's proposal would result in target earnings of approximately $29.5 million statewide, corresponding to a 10% earnings rate, based on our adopted definition of performance earnings basis. [footnote omitted] This compares to a historical average of approximately $38 million in earnings opportunity for avoided supply-side investments. (See Table 7.) TURN argues that, because shareholders do not put up the capital for DSM, utility shareholders are entitled only to a minimal management fee on ratepayers' investment. (Exh. 374, pp. 6-7.) Moreover, TURN points to the lack of earnings potential on power purchase agreements as further support for its position that any return above zero on DSM would make DSM more attractive to the utilities than supply-side alternatives. (Exh. 373, p. 5.}

"We disagree with TURN's conclusions and recommendations. As described above, the risks to shareholders from a power purchase agreement under traditional balancing account treatment is substantially lower than the risks under the DSM incentive mechanism we adopt today. It is therefore inappropriate to conclude that the earnings opportunity from DSM should be comparable to those types of resource acquisitions.

As we have acknowledged in our development of other performance-based ratemaking mechanisms, the imposition of increased performance risks on the utility is appropriately balanced by increased opportunity to earn. We have therefore incorporated such opportunity into recently adopted incentive mechanisms for both gas procurement and electric generation and dispatch. With regard to TURN's assessment of investment risks, we surmise the money managers would be demand considerably more than single-digit fees if they earned only in proportion to portfolio gains, as measured over a 7 to 10-year period, and if they were also required to pay for all losses on their clients' investments.

"Under DRA's proposal, the level of target earnings corresponding to DRA's proposed target earnings rates would be approximately $52 million statewide. This level also represents a substantial discount below the level of earnings opportunity available form avoided supply-side investments. (See Table 7.) However, DRA's reasons for this level are significantly different from those proferred by TURN. Unlike TURN, DRA believes that the starting for earnings comparability should be the earnings opportunity from a rate-based plant, assuming a 10-year amortization period. DRA then adjusts that level of earnings opportunity downward by 40-50% because, in DRA's view, current regulations "bias utility management toward choosing demand-side alternatives over supply-side options." [Exh. 341, pp. 31-33] DRA recommends a further (10-15%) reduction in earnings opportunity based on its assessment of relative performance risks. (Exh. 341, pp. 33-36.)

"In D.93-09-078, after considering a wide range of regulatory and financial factors that affected utility resource procurement decisions, including the ones described in DRA's testimony, we concluded that shareholder incentives are needed to offer utility management biases toward choosing supply-side alternatives over demand-side options. (D.93-09-078, mimeo. pp. 8-9, 27-28, RT at 3212 to 3220.0.) DRA justifies most of its reduction in earnings opportunity by asserting just the opposite. We have already ruled on this issue, and reject DRA's selective (and arbitrary) use of the testimony presented in an earlier phase of this proceeding to support its recommendations in this phase.

"Based on the evidence in this proceeding, we also find DRA's assessment of relative performance risks to be selective and incomplete. On the demand side, DRA overstates the risks to taxpayers, thereby understating shareholder risks. Although utility DSM programs can create many ratepayer risks, there was persuasive testimony presented in this proceeding that these risks have been mitigated by general rate case reviews, adoption of the ex post measurement protocols, and the relationship between performance and earnings under the shared savings proposals (Exh. 360, p. 10; Exh. 354, pp. 3-5, 7-9.) While DRA disagrees with others on the relative "rigor" of our adopted ex post measurement protocols, DRA still acknowledges that the implementation of ex post measurement protocols has shifted performance risk from taxpayers. (Exh. 341, pp. 34-36.) DRA Witness Schultz further testified upon cross-examination that this shift create higher shareholder risks due to factors both within and beyond the utility's control (RT at 5060-6061.) [footnote omitted] Moreover, DRA's analysis ignores the features inherent in shared-savings proposals that are designed to further shift performance risks to shareholders, such s the Panel 1 cost-effectiveness guarantee that we adopt in today's decision.

"In addition, DRA's analysis understates the ratepayer risks, and thereby overstates relative shareholder risks, associated with supply-side options. As discussed above, ratepayers assume significant performance risks under the current ratemaking treatment for many supply-side options, including fuel price forecasting risk and uncertainty in actual plant operating efficiency. DRA acknowledged on cross-examination that the risk that a utility power plant will fail to provide anticiated benefits or be more costly than anticipated is born primarily by ratepayers, assuming prudent utility management of the project. (RT at 4935 to 4936.) DRA also agrees that a utility's capital investment in a transmission and distribution project would be less risky for shareholders than an investment in a demand-side resource. (RT at 5059.) In addition, DRA does not disagree with the factual descriptions of the risk and rewards for DSM and supply-side resources, as presented in the Joint Submission. (Exh. 337; RT at 50 36.)

"In sum, we find that both DRA's and TURN's recommendatinos for target earnings rates are not supported by the record. Performance risks have been significantly shifted from ratepayers to shareholders by the ex post measurement protocols and performance features of our adopted incentive mechanism. At the same time, the adopted incentive mechanism gives utilities the opportunity to effectively manages those risks through portfolio diversification. The evidence in this proceeding indicates that a portfolio approach will substantially reduce utility exposure to penalties, and correspondingly increase the potential for earnings, relative to a program-specific application of the incentive mechanism. (See, for example, Exh. 346, 346B; RT at 3954-3955, 4450-4453.)

"As described in Attachment 1, a portfolio approach serves to decrease the absolute level of potential penalties, relative to a program-specific approach, whenever the penalty rate is higher than the earnings rate. This is because the programs performing in the deadband or earnings ranges will "pull up" the performance of the negative ones. In particular, when Panel 1's penalty rate of 100% is applied in aggregated program performance (i.e., on a portfolio basis), shareholders would be liable for 30% of the losses of individual programs if the overall portfolio is cost-effective. If the overall portfolio is not cost-effective, shareholders would be liable for 100% of the portfolio losses. (See Atachment 1, Cases 1C and 1D.)

"The evidence in this proceeding also indicates that the probability of falling into the penalty range is reduced under a portfolio approach, although the evidence is far from conclusive on the level of that reduction. Depending upon the number of programs in the portfolio, the TRC ratios of those programs, and the distribution of factors affecting performance, the estimated probability of falling unto the penalty range under a portfolio approach ranged from being negligible (less than 1%) to being quite significant (e.g., 50%). (See RT at 5020, 5295; Exh. 390, 390A, 394.)

"While we cannot predict with any precision the downside risks resulting from the combined features of our adopted incentive mechanism, we do conclude that they will be substantially less than if we applied those features to each individual program, as we have done in the past. Moreover, as discussed in Section 5.a. above, the upside potential from the adopted incentive mechanism is not capped or limited by declining earnings rates as it has been in the past. This serves to increase the overall potential earnings opportunity to shareholders when the utility performs beyond target.

"In our judgment, a 30% target earnings rate reasonably balances these considerations in light of the above considerations and our decision to include measurement costs in earnings calculations. (See Section III.D.) At this rate, the utility will receive an opportunity to earn that is significantly higher than current earnings rates, reflecting our observations that the performance risks associated with DSM have shifted from ratepayers to shareholders. This rate and corresponding target earnings levels are also within the range of earnings opportunity afforded to comparable supply-side investments, consistent with our own rules and the standards presented in the Energy Policy Act of 1992. [footnote omitted.] We choose an earnings rate at the lower end of this range to balance the significant risk-mitigating effects that portfolio diversification will have on shareholder exposure. At this rate, target earnings on a statewide basis are estimated at approximately $89 million, based on 1994 program year activities. The potential downside to the utilities is the full $215 million in estimated program costs. Should the utilities exceed their performance targets, they would continue to share net benefits with ratepayers at a 30% rate.

"Table 7 compares our adopted target earnings level for shared-savings programs with the earnings opportunity from representative avoided supply-side investments, historical DSM target earnings and the proposals in this proceeding. Table 8 presents statewide estimates of the potential upside and downside earnings levels associated with our adopted mechanism, compared with the proposals presented in this proceeding."

TABLE 7

COMPARISON OF SHARED-SAVINGS TARGET EARNINGS LEVELS:
AVOIDED SUPPLY-SIDE INVESTMENT AND
HISTORICAL, PROPOSED AND ADOPTED DSM
(pre tax $ millions, 1994)

	Avoided Supply-Side Investments	DSM 1990-1994 Annual Avg.	DSM-Proposed TURN	DRA	SoCal/WECC PANEL 1	DSM Adopted
PG&E	42.2-84.4	25.3	16.2	29.2	48.7	48.7
SCE	20.2-40.4	6.6	7.8	13.9	23.3	23.3
SDG&E	8.4-16.8	4.5	3.2	5.8	9.7	9.7
SoCal	6.0-12-1	1.7	2.3	2.9	7.0	7.0
Statewide Totals:	76.9-153.8	38.1	29.5	51.8	88.7	88.7

Notes to Table 7:

- The target earnings levels in this table were developed based on the utilities' 1994 program year data. (Exh. 336, Joint Tables C-1 to C-4.) These amounts would be recovered in four installments over a 7 to 10-year period after program implementation, assuming that verified performance is equal to target performance.
- Target earnings levels for avoided supply-side investments were calculated by applying the range of earnings rates presented in this proceeding (0.26-0.52) by the performance earnings basis adopted in this decision.
- For comparative purposes, parties' proposals have been conformed to today's decision by applying proposed target earnings rates to the definition of performance earnings basis adopted in this decision, and by including both retrofit and new construction programs in that calculation. For DRA's proposal, we directly apply DRA's recommended target earnings rates to the performance earnings basis rather than deriving shared-savings rates from a pre-specified target earnings level.
- Under TURN's proposal, utilities would not earn anything at target. At any point above target, the utility would earn at a 10% rate. For comparative purposes, we apply this rate to our adopted performance earnings basis, and include the results in this table.
- Historical averages are from Exhibit 337, pp. A-33 to A-36. These amounts were authorized and recovered in the year following program implementation.

TABLE 8

EARNINGS AND PENALTY ESTIMATES FOR 1994 DSM PORTFOLIOS
AT DIFFERENT LEVELS OF PERFORMANCE
($ millions, pre-tax)
Based on the Recommended and Adopted Shared-Savings Mechanisms

STATEWIDE TOTALS

Recorded PEB (% of Forecast)	Panel 1	SoCal	DRA	TURN	WECC	Adopted
200%	188	133	163	37	128	177
150%	141	133	58	18	117	133
100%	94	89	44	0	89	89
50%	47	0	22	-18	0	0
-30%	0	0	-53	-26	-18	0
-30%	-94	-32	-87	-47	-46	-89
-50%	-157	-45	-87	-55	-46	-148
-90%	-215	-45	-87	-71	-46	-215
-150%	-215	-45	-87	-102	-46	-215
Forecasted PEB:	314	295	295	367	298	295

NOTE: For comparative purposes, these calculations include both retrofit and new construction programs, and assume that the MPS is applied across all four earnings claims.

PEB = Performance Earnings Basis

These estimates do not include the effect of including measurement costs on forecasted performance or earnings.

Sources: Exhibits 348 A, B, C, and Exhibit 337, Joint Tables C-1 to C-4

(END OF APPENDIX 1 OF ATTACHMENT 2)